

Neuhoff, Karsten

Report

The Role of Contracting in European Electricity Markets

1st Report Future Power Market Workshop, DIW Berlin, 24.5.2013

Suggested Citation: Neuhoff, Karsten (2013) : The Role of Contracting in European Electricity Markets, 1st Report Future Power Market Workshop, DIW Berlin, 24.5.2013, Deutsches Institut für Wirtschaftsforschung, Berlin

This Version is available at:

<https://hdl.handle.net/10419/92986>

Standard-Nutzungsbedingungen:

Die Dokumente auf EconStor dürfen zu eigenen wissenschaftlichen Zwecken und zum Privatgebrauch gespeichert und kopiert werden.

Sie dürfen die Dokumente nicht für öffentliche oder kommerzielle Zwecke vervielfältigen, öffentlich ausstellen, öffentlich zugänglich machen, vertreiben oder anderweitig nutzen.

Sofern die Verfasser die Dokumente unter Open-Content-Lizenzen (insbesondere CC-Lizenzen) zur Verfügung gestellt haben sollten, gelten abweichend von diesen Nutzungsbedingungen die in der dort genannten Lizenz gewährten Nutzungsrechte.

Terms of use:

Documents in EconStor may be saved and copied for your personal and scholarly purposes.

You are not to copy documents for public or commercial purposes, to exhibit the documents publicly, to make them publicly available on the internet, or to distribute or otherwise use the documents in public.

If the documents have been made available under an Open Content Licence (especially Creative Commons Licences), you may exercise further usage rights as specified in the indicated licence.

The Role of Contracting in European Electricity Markets

Future Power Market Workshop, Berlin, 24.5.2013

Workshop report by Karsten Neuhoff¹

SUMMARY

Long-term energy contracts have featured prominently in many decisions of the European Commission to support the opening of the electricity markets. Contracts were seen to foreclose the market hence the Commission comprehensively unwound pre-existing long-term contracts and formulated strict criteria for new long-term contracts.² As a result, market participants are today reluctant to engage in long-term (e.g. 20 years) contracts. In recent years mid-term contracting (1-5 years), has played a far stronger role for risk management and investment in the practice of business. This has to date not been reflected in policy discussions. For example, most analysis of capacity mechanisms contrast the energy only spot market (day-ahead) without mid-term contracts with a capacity remuneration mechanism that offers several years contract coverage. This motivated the participants of the Future Power Market Platform to discuss the empirical situation with mid-term contracts, the mechanisms underpinning their price formation, and the implications of mid-term contracting for investment, re-investment, and closure of power stations, as well as for congestion management. We find that:

- Large discrepancies of mid-term contracting volumes across countries can reflect a variety of factors including regulatory design and consumer choices.
- Historically, investors were willing to undertake investment in liberalized electricity markets based on mid-term contracting and retail customer basis. With the scale of current uncertainties more security is needed to back new investments.
- Mid-term contracting can play a significant role in supporting re-investment choices and coordination of mothballing and closure decisions.

The discussion raised a set of questions that will be discussed in more detail in future meetings:

- What are the specific drivers for generation and different loads to sign mid-term contracting and what factors are constraining an increasing volume of such contracts?
- Can congestion management mechanisms enhance the liquidity of mid-term energy contracts by issuing transmission contracts of similar maturity so as to integrate different regional markets?
- The reference price for contracting is the short-term price. This raises the question how short-term energy prices are emerging and whether they reflect the value of system services provided?

¹ Head of Climate Policy Department at DIW Berlin and Professor for Energy and Climate Policy TU Berlin, kneuhoff@diw.de.

² Long-term contracts remained, for example, where they involved third countries like Switzerland.

Current situation with mid-term contracts

Actors, both on the generation and the demand side are inherently risk-averse and, thus, interested in mid-term contracts to hedge power prices. In sum, West-European generators sell about 20% of power 3-4 years before production and close to 100% of expected production one year ahead. There are, however, significant variations across countries and between domestic and industry customers. Retail customers are in large less price sensitive than larger consumers and thus offer a more inert customer base. Thus, vertical integration between generation and retail offers an alternative to mid-term contracts to provide a natural hedge for generation. It remains common across Europe, and has been re-introduced after initial unbundling in the UK. Vertical integration was part of the risk management strategy for major utilities when constructing power stations post liberalization. The total effect is limited to the extent that retail consumers only constitute about 1/3 of power demand.

Larger scale consumers are more optimizing than retail customers. In particular, industry switches very quickly if alternative offers are more attractive. Typical contract durations are in the order of 1-2 years. Some energy intensive users would be interested in signing contracts for 5-7 years to back larger-scale re-investment measures.

Mid-term contracting situations may vary significantly across EU countries. In new (eastern) European member states contract durations are typically significantly below the West-European average. But variations also occur in West-European countries, reflecting both consumer preferences and regulatory choices. Arguable private households in Norway are less risk averse than in Sweden. Thus, despite the significant variations of power prices linked to variations of hydro availability between years, Norwegian consumers have a preference for retail prices floating with the spot price in contrast to Swedish retail consumers that prefer to hedge this risk.

In Spain the last resort tariffs are set on a quarterly basis and seen as a benchmark for retail prices. Furthermore, regulatory adjustments (e.g. tax on generation) can be passed on to spot prices but would not be reflected ex-post in forward contracts. These two factors impact the ability of generation and load companies to sign mid-term contracts.

The inherent interest of generation to sell power on longer-term contractual arrangements can be also derived when modeling welfare under different risk profiles for generation and load. In scenarios that exclude the ability to sign contracts, the welfare declines. Generation can hedge most of the risk even using simple contract structure (e.g. only base load contracts). However, in a specific model scenario this would require a contract cover with base load contracts exceeding the total expected generation volume. This points to the importance of assessing the contract structures at times of evolving demand profiles.

In summary, mid-term contracting is an established procedure in many European countries. It is, however, usually limited to contracting up to four years ahead and in several countries contract durations are significantly shorter. Also, while most power is contracted year ahead, the share of contracting drops significantly for longer duration. Given the strong drivers for contracting both for generation and load, this raises the question on the constraining factors for mid-term contracting. Contracting volumes could be constrained by aspects related to counter party risk, or could be a result of risk management or other contracting procedures by companies.

Price formation

In general, it is expected that the price of a longer-term contract reflects the expected spot price of the contract. Where generators want to reduce downside risks of potentially very low spot prices, they could be prepared to sell power on longer mid-term contracts at a discount to expected prices. Actors on the load side might be prepared to pay a premium for power on mid-term contracts in order to avoid risks from volatile spot prices. Thus, the market price for mid-term contracts might in practice exhibit some up- or downward bias relative to the expected spot price.

Despite the theoretical result that points to a non-negative price range at which generation and load would be expected to be interested in signing mid-term contracts, in practice generation and energy intensive industry load report on the mutual interest in signing mid-term contracts but the inability to agree on a price acceptable to both parties.

The combination of demand reduction induced by the economic recession, large scale additions of renewable generation capacity to deliver EU renewable targets, and the historically low EU ETS allowance price resulted in record low wholesale power prices across Europe. Throughout this decade, sufficient conventional generation capacity seems to be available across European countries except for the UK and Poland that are expected to decommission a significant share of existing capacity. This is consistent with the low prices of contracts for the next 3-4 years.

Significant uncertainty seems to be associated with the price development, even within a five year horizon. If power stations not covering annual fixed costs were to be mothballed or decommissioned, then price levels could recover significantly. Also, economic development and, thus, recovery of electricity demand in the industry sector and the resulting impact on total power demand is uncertain.

The example of a new gas power station in southern Germany that is arguably required for system services and still incapable of recovering annual fixed costs raised the question on the appropriate remuneration of system services, including fast start capacity, high ramping rates, fault ride through capacity and the locational component of the service provided. Of further concern are out-of market interventions by transmission system operators. They could imply that generation does not recover the opportunity costs necessary to recover fixed and annual fixed costs.

System services are in Europe typically separately contracted. This raises the additional question to what extent they are reflected in short-term power prices and in mid-term contracts and whether the effect differs between market designs with a centralized clearing platform from bilateral market arrangements? In US states with liberalized power markets typically real time markets and usually also preceding intraday and day-ahead markets jointly optimize across energy, location and system services. In addition, virtual bidding can facilitate arbitrage of real time and day-ahead prices.

Implications for investment

European utilities have pursued significant investment in conventional generation assets in the liberalized market. This was typically decided against expectations of future developments, and only secured with mid-term contracts. Integration with retail and, thus, the household customer base arguably was the main driver and provided the best hedge. In this environment combined cycle gas turbines were particularly attractive, as they offered shorter lead and depreciation times, and, thus, created less reliance on future price forecasts. But also investments in more capital intensive assets like coal power stations were pursued.

New developments like the shale gas ‘revolution’ in the US and renewables deployment coupled with the economic crisis in Europe have reduced the scarcity value of generation assets and rendered many investments unprofitable. This illustrates the fact that utilities are now operating in a far more complex world. It is reflected in the scenarios against which they test investment choices. Traditionally, a few variables did suffice, but now dimensions like shale gas, PV prices, development of energy storage, demand response, and electric vehicles need to be considered.

In the short-term, with scenarios and the underlying assumptions differing to such large extends, utilities tend to postpone investments in fossil generation in Europe. In this (current) situation, it is more attractive to advance investment in countries outside of Europe, particularly where countries offer growing demand for power. In the longer-term, scenarios might converge again and stabilize around shared perspectives on technology and policy developments. As trust is re-established, utilities might be able to invest again on expectations of future market developments backed only by the hedge provided through mid-term contracts and the retail customer base.

This raises the question about the developments in the transition period. The situation might well differ across countries. Arguable, long-term contracts – e.g. for 20 years - could allow continued investment also in conventional generation assets. Feed-in tariffs and tenders effectively provide such long-term contracts for renewable generation assets across most European countries. However, due to the uncertainties about future input prices for fossil generation and difficulties to hedge these, long-term contracts are unlikely a perfect solution for conventional assets either.

Given the inherent counter party risk these long-term contracts would require government backing and therefore explicit government decisions on all investment in fossil generation. This might be particularly challenging where re-investment and therefore asymmetric information about the state of existing assets are involved. This raises the question how mid-term contracting is impacting re-investment.

Mid-term contracts help to stabilize revenue streams for conventional generation assets, as they are signed prior to the realization of the weather and demand pattern of a specific year and, hence, reflect an average price. Furthermore, as companies cannot predict wind and solar power generation for the period covered by mid-term contracts, they struggle to sign mid-term contracts. Hence, if a sufficient share of demand is interested in signing mid-term contracts, dispatchable, often fossil, generation capacity is likely to be the main counter party. On shorter time frames fossil generation might then meet the contractual obligation by acquiring wind or solar power if available at lower prices. This creates the opportunity for fossil generation to recover some margin – reflecting the capacity value they provide to the system.

Implications for re-investment and closure decisions

Surplus generation capacity in several European countries motivates companies to consider mothballing (time for re-operation 6-9 month) or decommissioning plants. Despite the expectation that gas power stations will add significant value to a future low-carbon power system, many of the power stations short-listed for closure are gas power stations.

The option value associated with the potential revenues of a plant in future years motivates companies to retain a power station online even if annual fixed costs are not recovered in the short-term. Where the balance sheet of companies is tight, or where major re-investments are required, the focus might shift from the potential future upside benefits to the costs of maintaining an unprofitable power station operating. This could encourage plant decommissioning or sale.

The difficulty and costs involved in decommissioning power stations also needs to be considered. Significant costs are linked to redundancy payments to staff, deconstruction and site clearance. Furthermore, regulatory requirements could increase costs and create delays. As a result, the capacity adjustment process is unlikely to be as smooth as one might have expected, but instead might be characterized by similar features previously associated with lumpy investment processes.

The challenge therefore is likely to be a challenge of coordination of re-investments, mothballing and decommissioning decisions across multiple actors. Failure of coordination could result in too large reductions of generation capacity at the wrong locations with high scarcity prices or temporary capacity shortages.

The coordination challenge is further complicated through strategic incentives which might distort the decisions of utilities and the credibility of information made available by utilities. Utilities benefit, if excess decommissioning results in scarcity in higher power prices for remaining generation assets. Utilities might aim to delay announcements of plant closures so as to encourage competitors to close plants, but equally utilities might attempt to prematurely announce plant closures where this could offer opportunities to negotiate additional support from regulators.³

Mid-term contracts might offer an elegant solution to facilitate this coordination without the need for regulators to micro-manage decisions in an environment of highly asymmetric information. Sufficient contract cover eliminates some of the strategic incentives for utilities, and revenue stability provided through contracts facilitates financing of re-investments. This raises the question whether the current contract durations and volumes are sufficient to allow mid-term contracts to deliver effective coordination of re-investment and closure decisions. If not – what could enhance liquidity and extent duration of mid-term contracts? How can additional information be provided to the market to support effective coordination?

³ An additional complexity appears in countries where decommissioning of power stations has been announced, like, for example, with the German nuclear phase out. Should potential surplus capacity be mothballed for use after the closure of the plant – and would private investors bridge the time period given the uncertainty about future market developments?

Implications for transmission

If liquidity and duration of mid-term energy contracts are central for an effective power market, transmission rights of corresponding duration gain in importance. Transmission rights between two pricing zones allow for the translation of some of the liquidity between the zones.

However, currently new transmission rights are only issued by European TSOs for the duration of one year. Given the evolving nature of congestion management this might be an appropriate decision to avoid that transmission contracts are issued that later turn out to be ill-defined as pricing zones are subdivided. In the workshop the question was also raised, what rights for generation (and duties for TSOs issuing the contracts) are associated with financial and physical transmission contracts.

Arguable, integrating the pricing zones into a single pricing zone could enhance liquidity. However, if transmission constraints are binding within such a zone, then the products traded in the energy market no longer match physical reality. In this case the ability of mid-term contracts to help coordinating for example the location of mothballing or plant closure is seriously infringed.

An alternative approach has been pursued in liberalized markets of the US. Most liquidity of energy trading is linked to trading hubs with a reference price defined by an average of nodal prices in a specified region. Liquidity and contract duration of energy traded in such hubs matches the most liquid European market (EEX). ISOs issue financial transmission contracts that allow companies on the generation and load side to hedge their location position relative to such trading hubs and to allow all market participants to arbitrage the prices across trading hubs.

The benefit of the US approach is that with nodal pricing matching the physical reality of the system, ISOs can issue transmission contracts without concerns about future reconfiguration of pricing zones. This raises the question how the European congestion management can develop, so as to provide a similar stability and, thus, allow issuance of transmission contracts to match contract durations of mid-term contracts.

The TSOs in the Scandinavian countries do not issue transmission contracts, but instead expect that market participants hedge locational risks through bilateral contracts of difference. As a result liquidity in some of the pricing zones is limited.